AL 2.1992-198
C.2

ERCB D 91-12

ERCB

Review of the Commissioning Date of Genesee Unit No. 1

CANADIANA
APR 22 1992

April 1992

Digitized by the Internet Archive
in 2016

https://archive.org/details/reviewofcommissi00albe

ERCB

Review of the Commissioning Date of Genesee Unit No. 1

Report to the Lieutenant Governor in Council

With respect to an application by The City of Edmonton
to amend Approval No. HE 8505

April 1992

ENERGY RESOURCES CONSERVATION BOARD
DECISION REPORT SERIES

Also in this series

79-AA	and Addendum: Alberta Power Limited Forestburg Collieries – Manalta Coal Sheerness Mine and Power Plant – and Edmonton Power – Genesee Power Plant and Coal Mine – Decision Report
80-B	Calgary Power Ltd. Keephills Power Plant Expansion – Decision Report
82-C	Generation Expansion 1985-1987 Keephills and Genesee Power Plant – Decision Report
D 83-H	Electric Generation Expansion 1985-1990 Sheerness and Genesee Power Plants – Decision Report
D 85-21	Electric Generation Expansion 1986-1991 Sheerness and Genesee Power Plants Decision Report

Report D 91-12 concerns

Application No. 910336 by Edmonton Power to amend Approval No. HE 8505 to allow construction of Genesee Unit No. 1 to continue.

Published April 1992 by:

Energy Resources Conservation Board
640 Fifth Avenue S.W.
Calgary, Alberta
T2P 3G4

Telephone (403) 297-8311
Fax (403) 297-7040

CONTENTS

SECTION		PAGE
1	BACKGROUND TO THE APPLICATION AND HEARING	1
1.1	Application	2
1.2	Planning Meeting	2
1.3	Hearing: Participants	2
2	DEFINITION OF THE ISSUES	3
3	FUTURE ELECTRIC ENERGY REQUIREMENTS AND ADEQUACY OF EXISTING SOURCES	3
3.1	Future Electric Energy Requirements	3
3.1.1	Views of the Applicant	3
3.1.2	Views of the Interveners	4
3.1.3	Views of the Board	4
3.2	Adequacy of Existing Sources to Meet Future Demand	7
3.2.1	Views of the Applicant	7
3.2.2	Views of the Interveners	8
3.2.3	Views of the Board	8
4	OPTIONS TO MEET THE NEED	9
4.1	Views of the Interveners	9
4.2	Views of the Applicant	10
4.3	Views of the Board	11
5	COSTS AND BENEFITS OF ALTERNATIVE COMMISSIONING DATES	13
5.1	Costs Incurred to Date	13
5.1.1	Views of the Applicant	13
5.1.2	Views of the Interveners	14
5.1.3	Views of the Board	14
5.2	Costs Related to Deferral of Construction	15
5.2.1	Views of the Participants	15
5.2.2	Views of the Board	16
5.3	Comparing Potential Costs and Benefits	16
5.3.1	Views of the Applicant	16
5.3.2	Views of the Interveners	17
5.3.3	Views of the Board	19
6	FINDINGS AND CONCLUSIONS	21
7	DECISION	24
	APPENDICES	25
	Appendix A Form of Approval – Genesee Power Plant	29

1 BACKGROUND TO THE APPLICATION AND HEARING

In early 1978, The City of Edmonton (Edmonton Power) applied to the Energy Resources Conservation Board (ERCB or Board) for approval to construct the Genesee power plant and commission its two generating units in 1985 and 1986 respectively. After reviewing the request in light of other options available at that time, the Board decided, in 1980, to approve Genesee Units 2 and 1 for commissioning in 1987 and 1988 respectively, for the reasons stated in ERCB Report 80-B and the Addendum to ERCB-AE Report 79-AA.

In 1981, Edmonton Power applied to the ERCB to advance the commissioning dates of the two units at Genesee to 1986 and 1987 in order to displace gas-fired generation in the mid-1980s. The application was granted for the reasons stated in ERCB Report 82-C.

In 1983, Alberta Power Limited (Alberta Power) applied to the ERCB for a deferment of the commissioning dates of the generating units at its Sheerness power plant as well as the Genesee units. The ERCB held a public hearing in which Edmonton Power intervened, opposing Alberta Power's proposal for deferment of the Genesee units. Subsequent to the hearing, the Board issued ERCB Report D 83-H in which it set new commissioning dates: Genesee Unit 2 in June 1988 and Genesee Unit 1 in February 1989.

In July 1984, the Electric Utility Planning Council (EUPC) issued a forecast which indicated significant decreases in future electric load growth. Subsequent to this forecast, TransAlta Utilities Corporation (TransAlta) and Alberta Power requested a new review by the ERCB of the commissioning dates of the Sheerness and Genesee generating units. A public hearing was held in early 1985 to consider this matter. At that hearing Edmonton Power again opposed any further deferrals of the commissioning dates of the Genesee units. The ERCB, however, decided in favour of deferment, setting new commissioning dates of October 1989 and October 1991 for Genesee Unit 2 and Unit 1 respectively. The Board's findings resulting from the hearing are discussed in ERCB Decision Report D 85-21.

In August 1986, the ERCB advised Edmonton Power that, based on the ERCB's electric energy forecast, the previously approved commissioning date (October 1989) of the first unit at Genesee, Genesee 2, was confirmed. The ERCB also indicated to Edmonton Power that the work on the second unit at Genesee, Genesee 1, should not proceed until a review of new electric energy forecasts confirmed its need.

In October 1988, Edmonton Power applied to the ERCB for a confirmation of the currently approved (October 1991) commissioning date of Genesee 1. The ERCB scheduled a public hearing to deal with this matter. However, because of other parallel developments that had an effect on the Genesee 1 commissioning date, the hearing was postponed several times. By late 1989, Edmonton Power withdrew the application and indicated that it could not meet the October 1991 commissioning date for

Genesee 1 stated in the approval. The ERCB recognized Edmonton Power's position but decided not to amend Approval No. HE 8505 until such time as a new commissioning date was determined.

1.1 Application

The Genesee power plant is located in the Genesee area, approximately 50 kilometres (km) west of Edmonton. It currently has one 400-megawatt (MW) generating unit which has been in continuous operation since October 1989 and has generated approximately 2700 gigawatt hours (GW•h) of electric energy per year. Construction of a second generating unit of similar capacity is currently suspended. The power plant is connected and delivers its power to the Alberta Interconnected System (AIS). The Genesee power plant is only one of more than 25 existing power plants in the province. In 1990, the AIS had a total installed electric generating capacity in excess of 7000 MW, which supplied an annual electric energy requirement of 38 850 GW•h and a peak power demand of 6092 MW.

On 1 March 1991, Edmonton Power submitted Application 910336 to the ERCB respecting the commissioning schedule of the second unit of the Genesee power plant, Genesee 1. It requested that, instead of prescribing a date by which the unit should be made available to the AIS, the ERCB should allow Edmonton Power to determine, based on monitoring load growth on the AIS, when the unit should be completed.

Edmonton Power requested an amendment to ERCB Approval No. HE 8505 to delete 1991 as the commissioning date for Genesee 1, and remove the current hold by the ERCB on construction work on Genesee 1.

The ERCB advertised the application for objections on 20 March 1991. A number of responses were received, several of which suggested that a public hearing should be scheduled to consider the application.

On 22 July 1991, Edmonton Power filed an amendment to its original application requesting an approval designating November 1993 as the commissioning date for Genesee 1 and a permit authorizing the immediate recommencement of construction.

1.2 Planning Meeting

The ERCB scheduled a meeting on 22 May 1991 to hear further representations respecting this matter. Particularly, the ERCB wanted to discuss whether there is a need for a public hearing or some alternative forum to consider the application and, if so, what the scope and timing should be.

On 5 June 1991, the ERCB issued a Memorandum of Decision in which it indicated that there were a number of matters raised by some of the participants at the meeting which could have an impact on the AIS and which required resolution before a completion schedule for Genesee 1 could be determined. Therefore, the Board decided to schedule a public hearing to consider these matters.

1.3 Hearing: Participants

A public hearing to consider the appropriate commissioning strategy for Genesee 1 was held in Calgary during 15-16 August 1991, with J. P. Prince, Ph.D., F. J. Mink, P.Eng., and R. G. Evans, P.Eng., sitting. Those who appeared at the hearing are listed in Table 1.

2 DEFINITION OF THE ISSUES

The Board has considered the application, submissions, and testimony provided at the hearing and considers the relevant issues to be

- future electric energy requirements and adequacy of existing sources,
- options to meet the need, and
- costs and benefits of completing Genesee Unit 1 to meet the need.

3 FUTURE ELECTRIC ENERGY REQUIREMENTS AND ADEQUACY OF EXISTING SOURCES

3.1 Future Electric Energy Requirements

3.1.1 Views of the Applicant

Edmonton Power presented both the 1990 and 1991 EUPC Electric Forecast Working Range for Planning Resources Addition. It explained that, after a review in 1991, the EUPC adopted the 1990 forecast as appropriate for 1991 (see figure on page 5).

Edmonton Power submitted that it relied on the 1991 EUPC Electric Forecast Working Range to predict future electric requirements because (i) it is the only forecast agreed to by all EUPC members; (ii) it reflects results of recent reviews; and (iii) it relies on a number of forecasts prepared by outside organizations. It stated that the load is expected to fall within the EUPC working range, i.e. between the high and low cases, with a 70 per cent probability.

Edmonton Power indicated that the peak demand forecast was based on a 3.5 per cent growth for the high load growth scenario and a 1.4 per cent growth for the low load growth scenario. It also indicated that actual load growth in the 15-year period ending in 1989 had been 5.6 per cent, and that the actual peak demand for 1990 exceeded the projected high scenario value for 1990.

Edmonton Power further indicated that actual growth of energy demand recorded from January 1991 to July 1991 was in the order of 5.2 per cent. It compared this figure with the 6.2 per cent energy growth predicted by the high load growth scenario and the 2.8 per cent predicted by the low load growth scenario and concluded that actual growth was closer to the high load growth scenario.

Edmonton Power also presented an average forecast, which it indicated was simply the arithmetic mean between the high and the low load growth scenarios.

During cross-examination Edmonton Power acknowledged that the utilities' short-term add-up forecast showed higher levels of interruptible loads than the EUPC high load growth scenario. However, Edmonton Power stated that it considers the short-term add-up forecast to be inappropriate for long-term generation planning. It explained that this forecast is not a forecast that the utilities produce cooperatively. Rather, it is just the addition of the forecast that each utility prepares for operational purposes in the short term.

3.1.2 Views of the Interveners

The Industrial Power Consumers Association of Alberta (IPCAA) argued that a sizeable amount of new industrial load is interruptible and that a fair amount of existing firm load is converting to interruptible. It pointed out that the EUPC forecast of interruptible loads is 390 MW for the high load growth forecast and 315 MW for the low forecast in 1992. However, IPCAA mentioned that the utilities' short-term add-up forecast, which is obtained by adding the short-term forecasts produced by each utility for operational purposes, indicated some 567 MW of interruptible load in the same year. IPCAA also stated that 1991 actual loads suggest that the EUPC high forecast would not materialize.

The City of Calgary claimed that actual energy demand figures recorded from January 1991 to July 1991 were very close to monthly loads predicted by the EUPC low load growth forecast for the same months in 1991.

Alberta Power indicated that the utilities' short-term add-up forecast in 1992 is closer to the EUPC low growth forecast than the high growth forecast in both energy and capacity. It also indicated that 1991 actual energy use and peak demand were close to those predicted by the EUPC low growth forecast.

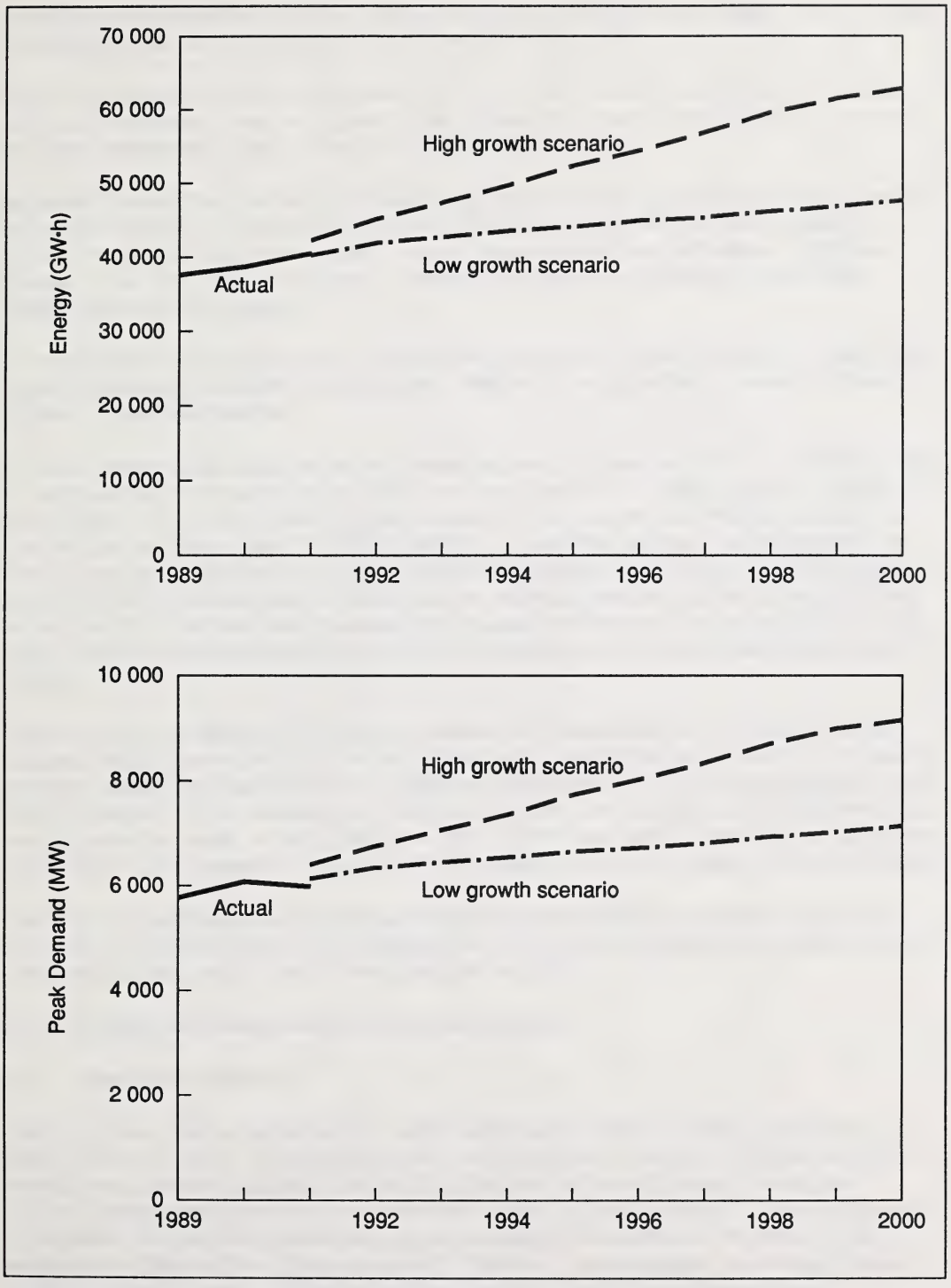
TransAlta accepted that loads at least as high as the EUPC low growth forecast would likely materialize; however, there is less chance that loads as high as the EUPC high growth forecast would materialize.

3.1.3 Views of the Board

The Board analysed the various forecasts of electricity demand identified by Edmonton Power with a view to understanding what Edmonton Power referred to as the "window of need" for new generation. This window ranges from the earliest date to the latest date on which new capacity might be needed in the AIS, given reasonable assumptions about growth in demand for electricity. The earliest date – the opening of the window – is tied to the high forecast of energy requirements. Edmonton Power's submission adopted the EUPC's 1990 and 1991 high forecasts, the latter being a review and confirmation of the 1990 forecast.

The Board questioned the range of the load forecasts submitted by Edmonton Power, given the current economic circumstances in the province. Accordingly, the Board decided to subject both the 1990 and 1991 forecasts to detailed assessment, particularly with respect to the assumed industrial project profile, which might be altered given more current information than was available when the EUPC's forecasts were developed. Applying adjustments that incorporate a more current view of potential developments in petrochemicals, gas reprocessing, and metals sectors yields a reduction from the EUPC's 1990 high forecast of peak demand by 80 MW in 1993 and by 232 MW in 1994. The Board also evaluated the low forecast and Edmonton Power's average forecast case on the same basis but focused on the high forecast to test the earliest need for new facilities.

The adjustments the Board made are as follows: In the petrochemical sector, it deferred the commissioning of the Dow chemical plant to 1995, thereby also deferring possible energy demand from derivative plants. In the gas processing sector, the Board considered slow growth to be likely for some time and projected that all expansion of gas reprocessing facilities will occur beyond 1994. In the metals sector, it assumed a reintroduction of the Magcan magnesium plant at High River as a



1991 EUPC ELECTRIC FORECAST AND ACTUAL LOAD

D 91–12
ERCB

possibility in a high forecast for 1993. As noted above, the net effect of these changes was to reduce the forecast of peak demand by 80 MW in 1993 and 232 MW in 1994.

Although the Board did not explicitly quantify the effect of this reduced industrial activity on other sectors of the economy, it was recognized that the ultimate high forecast would likely be lower than the adjusted amount as a result of lower consumption in other sectors.

The Board also examined the other components of the EUPC forecast, including the assumed level of interruptible loads in the forecast of load growth. The Board accepts that the trend suggests a growing interruptible load on the system; however, the evidence did not substantiate a significant departure in the short run. Accordingly, it concluded that these components are acceptable for planning purposes in this instance.

The result of these adjustments was to reduce the projected growth in peak demand for the high case forecast developed by the EUPC as noted above. Whether or not that affects the window of need is discussed in subsequent sections.

The Board notes that the actual annual peak demand recorded in December 1991 was 5985 MW. This is lower than the peak predicted by the EUPC low growth scenario for 1991 by almost 140 MW (see figure on page 5). A rate of growth of peak demand of 8 per cent per year would be necessary to reach the load predicted by the 1991 EUPC high forecast for 1993, while a 4 per cent growth rate would be needed to reach the load predicted by the low forecast for the same year. Based on these records, the EUPC Working Range Forecast may be optimistic; however, the Board recognizes that the recorded 1991 peak has been influenced by an unusually mild winter. In any case, the Board is satisfied that the adjustments made to the EUPC high forecast result in a more likely high scenario forecast.

The Board also notes that the EUPC forecast accounts for potential load served by self-generation. This load, which is subtracted from the total Alberta load in the calculations of need for new capacity, represents the portion of the load the EUPC believes would be served by industrial cogeneration units installed primarily for self-consumption. The Board is of the view that the impact of load served by new self-generation would be very small in the 1993 to 1994 time frame. Therefore, for the purpose of this decision, it is prepared to accept the EUPC estimate as part of the electric forecast at this time.

The EUPC forecast incorporates only demand side management that is attributable to rate structure, for example, interruptible loads. Other demand side management incentives will presumably play a greater role in future applications for new generation capacity.

3.2 Adequacy of Existing Sources to Meet Future Demand

3.2.1 Views of the Applicant

Edmonton Power determined the need for additional capacity based on the 1991 EUPC Electric Forecast Working Range. It stated that capacity would be needed as early as 1993 if the high load growth forecast materialized and as late as 1998 if the low load growth forecast materializes. Edmonton Power stated that Genesee 1 is required to assure a supply of power to meet load demand, to compensate for unexpected major unit outages, to maintain shareholders' confidence, and to maintain the utility's ability to plan strategically. Therefore, it recommended completing Genesee 1 for 1993 to minimize risk to AIS reliability if the high load growth forecast materializes.

Edmonton Power calculated a 179-MW deficit in load carrying capability (LCC) in 1993 under the high load growth forecast. It indicated that approximately 255 MW of installed capacity would be required to provide the 179 MW of LCC required in 1993. Under the low load growth forecast, a deficit of 60 MW of LCC would exist in 1998.

Edmonton Power assumed no reliance on small power producers' (SPP) units in the calculations of LCC because it did not know what amount of capacity SPP units would be able to contribute to the AIS. It also did not include the presently approved Medicine Hat units because it believed that the approval of those units was not intended to affect the timing of Genesee 1.

3.2.2 Views of the Interveners

Alberta Power submitted that even if additional capacity were required in 1993 to meet the high load growth forecast, Genesee 1 should not be built. It suggested there are other short-term options that could be exercised, thereby delaying the need to spend $177 million to complete Genesee 1 in 1993. It recommended that the subject application should be deferred pending a review in 1992 to determine if Genesee 1 would be needed for 1994.

TransAlta concurred with Edmonton Power that there is a possible need for additional capacity as early as 1993. However, it submitted that there are other options and other supply sources totalling in excess of 300 MW of firm capacity that should be considered as alternatives for satisfying potential need in 1993. It stated that costs, as well as reliability, must be taken into consideration.

TransAlta submitted that the calculations of need should include the approved capacity at Medicine Hat. It also submitted that consideration should be given to capacity which may be added to the system for reasons other than system-wide reliability, such as the proposed 40-MW Rainbow Lake expansion and SPP units, which could account for 80 MW in 1993, as forecasted by the Small Power Producers Association of Alberta.

The City of Calgary submitted that new plants should be added only when needed. On that basis, it would be more appropriate to commission Genesee 1 in 1994.

3.2.3 Views of the Board

In calculating the existing LCC of the AIS, the Board used the 1991 Generation Planning Characteristics, which were published shortly after the hearing, because they represented the most current information on load shape and generating unit performance.

The 179-MW deficit calculated for 1993 by Edmonton Power would be smaller by 80 MW under the adjusted high forecast based on the Board's assumptions. It is, therefore, necessary to determine whether or not existing capacity could meet the smaller deficit of 99 MW of LCC.

Edmonton Power excluded both small power and generating capacity in Medicine Hat when calculating the deficit. The Board believes that approach is inappropriate.

The City of Medicine Hat's load, together with its full generating capacity, has always been included in calculating the LCC of the Alberta interconnected system. No evidence was presented to support the position that the recently approved units in Medicine Hat should not be included in the calculations of LCC. The Board considers it appropriate to include them.

The Board also estimates that, by the end of 1993, there could be close to 40 MW of capacity installed under the Small Power Research and Development Program. This total capacity, which corresponds to the capacities of plants that are already operating and plants that are currently under construction, is made up mainly of hydroelectric and thermal units.

The Board notes that technologies used by these SPP plants are well developed and are not significantly different from existing utility-owned facilities. Therefore, the Board believes that these SPP plants will perform as efficiently and as reliably as any utility-owned facility of similar type. Accordingly, the Board considers it appropriate to include these SPP units in the calculations of LCC, with the proper recognition of seasonal water flows available to hydro units.

The Board is of the view that it would be imprudent to include other SPP units whose future remains uncertain, even though some of these have ERCB approval.

Even using the lower, adjusted, high forecast, and including Medicine Hat capacity and small power as part of existing capacity in 1993, the LCC falls short by 70 MW. Therefore, other sources of supply would be necessary to meet the need, should the high case materialize. On this basis, the Board concludes that Genesee 1 could be needed to meet the peak load demand as early as 1993.

The Board notes that the actual rate of growth of electric energy from 1989 through 1991 was approximately 4 per cent per year and believes that, given the likely growth of the Alberta economy, it is unlikely that even the adjusted high case load would materialize. It believes a more realistic outlook of energy demand would be closer to the average load growth forecast as presented by Edmonton Power. This would mean existing capacity would be sufficient during 1993, but it is reasonable to expect that some additional generation would be required for the 1994/95 climatic peak.

4 OPTIONS TO MEET THE NEED

During the course of the hearing, the following other supply options to meet the need for generating capacity on the AIS were discussed:

- firm capacity purchase from British Columbia (B.C.)
- capacity assistance from Saskatchewan Power Corporation (SPC)
- new thermal capacity in the Rainbow Lake area
- acceptance of a lower level of reliability
- refurbishment of Rossdale units

4.1 Views of the Interveners

Alberta Power suggested that reliance on the SPC tie-line could be advanced to 1993. However, it acknowledged that there is no guarantee that the 125 MW of capacity assistance from SPC could be made available in 1993, but stated that there is also no guarantee that there would be a need for capacity in 1993. Alberta Power also indicated that it is currently investigating a project that would require the installation of a 40-MW gas turbine in the Rainbow Lake area. This project, if approved,

could be an option to supply a shortfall of capacity in 1993, if the high load growth forecast materializes. It further indicated that, given the transmission losses in the lines that interconnect central Alberta to the north, the addition of 40 MW of generation at Rainbow Lake would free 60 MW in central Alberta.

TransAlta proposed the purchase of 150 MW of firm capacity over and above the current reliance of 400 MW on the B.C. tie as an option to meet any shortfall in 1993 if the high load growth forecast materializes. TransAlta stated that relying on the tie for a total of 550 MW would not create operational problems, such as requiring more spinning reserve.

In general, TransAlta proposed a flexible planning approach because, in its view, flexible planning allows consideration of all economic options to meet an uncertain demand. It explained that under flexible planning, decisions could include the initiation, acceleration, deferral, and cancellation of projects, or even the acceptance of increased risk associated with a temporary reduction in reliability levels. TransAlta indicated that Genesee 1 is one of the options to meet the high load growth forecast for 1993 but the costs, benefits, and risks of preserving it as a 1993 option must be assessed against the costs, benefits, and risks of other options, especially if they involve shorter lead times. TransAlta recommended that the Board adopt the flexible planning approach.

TransAlta submitted that in order to meet the low load growth forecast, a good long-term option (such as Genesee 1) would be appropriate even if it involves high capital expenditures. However, to respond to the less likely high load growth forecast, short lead-time and even high-cost options should be examined because they may never be needed and even if needed, it would be for a short time. TransAlta recommended a review in 1992, when one more year of actual load growth experience would have been obtained, to determine if Genesee 1 would be needed for 1994.

IPCAA endorsed TransAlta's flexible planning approach because it believes that big plants should not be built to meet the high load growth forecast; doing so would only preclude consideration of any other options.

IPCAA suggested the acceptance of a lower level of reliability as a temporary alternative to the potential shortfall in 1993, if the high load growth forecast materializes. It also suggested that the Rossdale Units 2, 3, and 4 could be refurbished before 1993 as another alternative, and that a short-term purchase of interim capacity was also an alternative.

The Alberta Cogeneration Council submitted that all viable energy sources such as cogeneration, independent producers, etc. should be given consideration as alternatives to Genesee 1. It argued against the "big-block" approach to generating capacity for planning purposes.

Fording Coal submitted that there was no evidence to support the practicality or reliability of alternative options to Genesee 1 in 1993.

4.2 Views of the Applicant

Edmonton Power submitted that TransAlta's proposal of purchasing 150 MW of firm capacity, over and above the current reliance of 400 MW from B.C., was not substantiated. It indicated that B.C. Hydro delayed its construction program until after the year 2000. Furthermore, B.C. Hydro is relying on non-utility generation to supply future needs although it does not have experience with non-utility generators. Edmonton Power also indicated that B.C. is a hydro system, which means that it is

dependent upon rainfalls and snowfalls. Therefore, Edmonton Power submitted that the availability of capacity from B.C. was uncertain.

Edmonton Power stated that it did not consider any capacity assistance from SPC before 1995, as prescribed by ERCB Decision D 87-14. It also indicated that uncertainties exist in Saskatchewan in relation to SPC's generation expansion plans.

Edmonton Power submitted that the Rainbow Lake project referred to by Alberta Power as an alternative to supply a potential shortfall of generating capacity has not come before the ERCB. Therefore, Edmonton Power did not give it any status for generation planning for the AIS.

Edmonton Power submitted that accepting a lower level of reliability as an alternative to adding generating capacity would require public participation, EUPC involvement, etc. Edmonton Power was of the view that it cannot look at this option in isolation, particularly since there is a reliability criterion in place which has been endorsed by the ERCB.

Respecting the idea of refurbishing some of the Rossdale units, Edmonton Power indicated that it would be better to spend the money finishing Genesee 1, which is a new plant, rather than spending it refurbishing the Rossdale units, which are 35 to 50 years old.

Edmonton Power submitted that TransAlta's proposed flexible planning approach had no relevance in this situation where existing capital expenditures were in the region of $350 million, and the possibility of completing 400 MW for less than $90 million exists. However, Edmonton Power indicated that it would support flexible planning for future projects, when the rules are known before the game starts.

Edmonton Power acknowledged that a short-term capacity deficiency could be met with alternative sources but pointed out that the long-term costs will increase if alternative sources are used to defer Genesee 1. It also indicated that consumers in Alberta are long-term users of electric energy. Therefore, Genesee 1 represents the most cost-effective alternative, particularly given the relatively small amount of money needed to complete the unit.

4.3 Views of the Board

The interveners advanced several options that might meet the need, and stated the options that might be more appropriate if the need were realized in 1993. The options included reliance on neighbouring power systems, installation of new generating capacity, refurbishment of existing generating capacity, and perhaps acceptance of lower standards of reliability. All of the suggested alternatives were proposed as short-term solutions if capacity fell short because of a 1- or 2-year deferral of Genesee 1.

The Board acknowledges, as a possible supply option, the possibility of contracting 150 MW of firm capacity purchase from B.C., over and above the current reliance of 400 MW. While the availability of that capacity is somewhat dependent on the success of the Power Smart Program, self-generation, independent power producers in B.C., and other contractual agreements B.C. Hydro may have with other utilities, the Board accepts the possibility that short-term uncertainties in load growth might be met through greater reliance on B.C. This would be particularly relevant for small shortfalls in capacity. However, based on the evidence provided at the hearing, the Board cannot accept this as a prudent alternative to completing Genesee 1. The Board will expect detailed assessment of increased

reliance on the B.C. tie in future applications for new generating capacity and in upcoming reviews of parameters related to generation planning.

While Alberta Power's proposal of advancing the reliance on the SPC tie-line from 1995 to 1993 as a possible option to supply a potential 125-MW shortfall in the AIS during the 1993-1994 period is interesting, the Board found insufficient evidence to suggest it is a realistic option in the short run. The Board notes that the approval of this tie envisioned its dedication to the needs of Saskatchewan until 1995.

Alberta Power indicated it was currently preparing an application for a 40-MW gas turbine in the Rainbow area, and that such generating capacity, if installed, could free approximately 60 MW of generation in central Alberta. The Board believes that, until the application is filed and the merits of the proposal fully reviewed, it should not be a factor which influences the decision respecting Genesee 1.

IPCAA did not provide any evidence that would allow testing of its proposal for refurbishment of the Rossdale units. The lack of evidence leaves the Board unable to determine if such a proposal is in the public interest or if it is a better alternative to completing Genesee 1. Moreover, such evidence is particularly important given the age of the Rossdale units. Therefore, it cannot consider this proposal in arriving at its decision.

With respect to accepting a lower standard of reliability, the Board would consider that as a viable option in some circumstances, if a concrete proposal were brought forward and, as suggested by Edmonton Power, discussed widely and accepted by other interested parties. The Board notes that the utilities, together with all the stakeholders, are currently in the process of reviewing, among other things, the standard of reliability desired for the AIS. Therefore, until such time as a new standard of reliability is established, the Board will use the current reliability criteria.

Of all the alternatives discussed at the hearing, only those that involve capacity assistance from adjoining provinces were given some costs figures. TransAlta estimated a 1-year purchase of firm capacity from B.C. to cost between $6 and $12 million. Alberta Power quoted a $4-million cost to advance the reliance on the SPC tie to 1993 with an associated energy cost of between 1.4 cents to 2.4 cents per kW•h. The Board is of the view that these costs estimates are insufficient to allow a comparison of cost effectiveness between the Genesee project and these alternative options.

The Board agrees there are potential savings from a flexible approach to generation planning over time, as stated by TransAlta. The Board believes such flexibility will be increasingly valuable in the future, and will expect to see it addressed in future applications. However, the application to construct the plant has been approved; the question now is one of timing. There is little scope for the application of flexible planning concepts in this situation.

The Board concludes that there may be options immediately available that, taken together, could meet unforeseen load growth in the short term and possibly even supplement long-term supply in future. Some of the options could be pursued on short notice to hedge against inordinately high demands in 1993, while all should be evaluated for their role in the supply pool over a longer period. In the meantime, little evidence was presented to support and substantiate these alternatives, or to allow a meaningful comparison between them and the Genesee project. In short, the Board accepts that the most reliable option before the Board to meet the firm baseload needs of the AIS is Genesee 1.

5 COSTS AND BENEFITS OF ALTERNATIVE COMMISSIONING DATES

5.1 Costs Incurred to Date

5.1.1 Views of the Applicant

Edmonton Power identified three categories of expenditure involved in the Genesee project: (i) spent, (ii) committed to be spent, and (iii) uncommitted but remaining to complete the project.

Edmonton Power testified that, when the Board ordered it to stop construction of Genesee 1, it had spent approximately $84 million on capital costs only, to the end of 1986. It interpreted the ERCB stop order to mean that no more construction on the site should be done, although equipment orders were honoured if they were ordered prior to that date. It noted that turbines and boilers were ordered in 1982. However, it stated that there were payments that Edmonton Power had to make for equipment that was being manufactured. This equipment was delivered; therefore Edmonton Power had to keep some personnel on site to take delivery.

Edmonton Power submitted that it had spent and committed $350 million on Genesee 1 to mid-1991, and $90 million remains to be spent to bring the project on line in 1993. Since the $90 million included an allocation of $30 million for contingency, which might not be needed, Edmonton Power concluded that the additional costs of completing Genesee 1 in 1993 could be as low as $60 million. It also pointed out that the interest cost on the capital already expended would be $233 million even if Genesee 1 is commissioned in 1993.

In response to TransAlta's and Alberta Power's questioning regarding need, cost, and expenditures associated with the second dragline, Edmonton Power responded by citing the following reasons for needing a second dragline: (i) shallow coal was not available, (ii) pre-stripping was found uneconomic, and (iii) there were coal handling difficulties. Edmonton Power also testified that the contractual cost of the second dragline was $64 million and that the purchase order had been placed in July of 1989. It explained that it has already spent $14 million on the dragline which has been included in the $199 million total spent. All remaining costs of the dragline were included under committed expenditures because it was contractual.

Edmonton Power testified that it and Fording Coal were equal partners in the purchase of the dragline. Therefore, Edmonton Power's share of the dragline cost was included as capital costs, while Fording Coal's portion showed up as fuel costs for Genesee 1.

Edmonton Power testified that in 1988, it informed the ERCB that it had to take delivery of major equipment components in order to keep the approved commissioning date of 1991 possible and that the ERCB had authorized Edmonton Power to do so. Edmonton Power stated that the expenditures on Genesee 1 were only incurred as required to meet previous commissioning dates.

Edmonton Power stated that any expenditures on the boiler were included in the total amount spent up to December 1990. It submitted that if Edmonton Power had not erected the boiler, but instead had stored it horizontally at the site for a 2-year deferral, the project cost would have increased by $11 million. It also stated that the total boiler erection cost was $21 million and that, to the end of 1990, Edmonton Power had spent $10 million of the total erection costs. The remaining $11 million

was included in the total $286 million committed. Edmonton Power also mentioned that, to June 1991, it had spent $13 million on erection of the boiler.

5.1.2 Views of the Interveners

The interveners generally argued that Edmonton Power's expenditures on Genesee 1 were excessive in light of the stop construction order in effect since 1986.

Alberta Power stated that when the ERCB directed the utilities to stop construction of Sheerness 2 and Genesee 1, Alberta Power not only stopped construction but it also limited its expenditures on many related costs. However, Edmonton Power did not stop expending money on Genesee 1. It also indicated that since contracts for Sheerness 2 were let earlier than 1982, the year in which Edmonton Power let the contracts for Genesee 1, and Alberta Power managed to either defer or cancel contracts, Edmonton Power should also have been in a position to do so. Alberta Power submitted that because Edmonton Power kept spending on Genesee 1 while Alberta Power stopped spending on Sheerness 2, the ERCB, in 1984, reversed its original decision and approved construction of Genesee 2 ahead of Sheerness 2.

TransAlta and Alberta Power also questioned Edmonton Power on the need and costs of the second dragline. They suggested that the existing dragline might be sufficient to supply the coal needs of the two units at the Genesee power plant.

IPCAA questioned Edmonton Power's interpretation of the ERCB's stop-work order and suggested to Edmonton Power that the stop-work order meant to not do any more construction and to not spend any more money on Genesee 1.

An area of major expenditure since the stop-construction order has been the boiler. IPCAA also pointed out that the 12 May 1989 letter from the ERCB, included in Alberta Power's submission to the hearing, stated that expenditures on the boiler were authorized on the basis that it was Edmonton Power's business decision and should not be considered in determining the need and timing of Genesee 1. Therefore, this cost should not be included in the calculation of carrying charges done by Edmonton Power.

W. Arsene contended that the stop-work order meant to stop everything and that all costs incurred by Edmonton Power after the 1986 stop-work order should be borne by Edmonton.

5.1.3 Views of the Board

The Board considers the expenditures made by Edmonton Power on the Genesee 2 Unit to be subject to review by the Public Utilities Board (PUB). A review of the correspondence to Edmonton Power regarding the construction of Genesee 1 indicates the direction given was general in nature. The Board believes the general intent of that direction was to have Edmonton Power stop activity in a cost-effective way to maintain cost controls on its project and limit expenditures to minimize long-run costs. The prudence of the expenditures will ultimately be determined by the PUB.

The Board accepts Edmonton Power's position that, had the boiler not been erected at the time of delivery, the total project cost would have increased by $11 million. Therefore, the Board accepts that the erection of the boiler was a reasonable expenditure. The Board also notes that the purchase order for the second dragline was placed in July 1989 to meet a 1991 commissioning date. This is

prior to the Board's acknowledgement that the unit could not be completed for a 1991 commissioning date. Therefore, for purposes of its analysis, the Board has included the money already spent on the dragline as well as the costs associated with the erection of the boiler in the $199 million spent to the end of 1990. In summary, for purposes of its evaluation, the Board has adopted the capital cost estimates shown on Table 2. These costs are the same as those provided by Edmonton Power.

5.2 Costs Related to Deferral of Construction

5.2.1 Views of the Participants

Edmonton Power submitted that since all major equipment was either sitting at the site or stored off site, only assembly is necessary to commission Genesee 1. It indicated that assembly would take approximately 24 months, and that could be shortened by 3 months, although at a significant cost.

Edmonton Power explained that the cost increases were due to escalation on contracts, extension of warranties, extension of bonds, administration costs, storage cost for equipment, and refurbishment of equipment when taken out of storage. It also explained that committed costs referred to contracts in place containing a contractual liability to specific expenditures.

Edmonton Power argued that it is better to build Genesee 1 now because there is union stability in the province: contracts have been settled for the next 2 years but they will expire in 1993. It also submitted that the boiler warranty had been negotiated for 1993, 1994, or 1995 completion. It indicated that the boiler contractor was not willing to extend the warranty beyond 1995.

Edmonton Power also submitted in its application that building Genesee 1 for 1993 would have positive social benefits to Alberta. It estimated that completion of the project will require the expenditure of $62.5 million on Alberta products and labour, with a direct labour component of $47.6 million.

Edmonton Power also argued that it prefers a definite commissioning date rather than a deferral of the decision to next year because postponing the decision would leave uncertainty, would create difficulty with contracts and possibly bonding companies. It also indicated that continued deferral risks deterioration and obsolescence of major plant modules.

Edmonton Power submitted that the Board's decision would have broad implications because it would affect the willingness of utilities in this province to make future investments in large-scale generation projects. It explained that two fundamental principles motivated Edmonton Power to propose Genesee: (i) the government's coal policy and (ii) the EUPC's endorsement of one-system planning. However, it indicated that the short-term savings due to past deferrals were insignificant in relation to the long-term cost ramifications, and that no apparent consideration was given to the taxpayers of Edmonton when deferrals were proposed.

The Northern Alberta Building Trades Council and Provincial Building Trades Council, together with the Northwest Territories Building and Construction Trades Council (the Trades Councils) estimated additional costs of $8 million attributable to higher labour costs if the project is delayed beyond the expiry date of current labour agreements.

5.2.2 Views of the Board

The Board accepts the general argument that maintaining a plant that is well over half constructed in a state of indefinite suspension risks incurring greater costs than completing the plant. Costs associated with warranties, risk of obsolescence, storage, and conditions in the labour market must be recognized in an assessment of costs of alternative sources of electric energy. For such costs to be acceptable, there should be well-defined benefits to society to offset them: such benefits could be in the form of lower costs of alternatives if they are well-defined, available alternatives. It should also be recognized that although existing expenditures on Genesee 1 represent sunk costs, they must ultimately be borne by consumers, regardless of what other generating capacity is added to the system. The Board also accepts that current workforce availability and wage stability may lead to some economic benefits, if the plant is completed within a reasonable period of time.

5.3 Comparing Potential Costs and Benefits

5.3.1 Views of the Applicant

Edmonton Power stated that substantial benefits will be realized as soon as Genesee 1 becomes operational. These benefits occur because more expensive generation on the AIS will be displaced by the less expensive generation by Genesee 1. Edmonton Power stated that these operating benefits are greater than all relevant costs and therefore justify bringing Genesee 1 onstream for 1993 even if it is not required to meet a capacity deficit.

Edmonton Power estimated the net savings would be in the order of $15 million (present worth to 1993) if Genesee 1 is built in 1993 instead of 1994, the average load growth forecast materializes, and the Chenery Dobson gas price forecast materializes. It also estimated net savings of $32 million if the low load growth forecast materializes and Genesee 1 is built in 1993 instead of 1998. Edmonton Power further explained that these savings were net of fuel, operating, and maintenance costs of running Genesee 1 as well as the carrying cost of commissioning the unit ahead of need. The latter cost was based on $177 million needed to complete the unit in 1993.

Edmonton Power submitted that it used a gas price of $2.18 per gigajoule (GJ) in 1993 to compute fuel-displacement benefits. To arrive at this gas price, Edmonton Power took the field gate price given by the average gas price forecast in 1989 dollars, inflated it at 5 per cent per year, and added transportation costs and other costs that relate to transportation. Edmonton Power stated that the average price of gas was appropriate for the benefit analysis. It expected that after various pipeline projects were completed, gas supply and demand would balance around the average price rather than being depressed by excess supply in spot markets, as is happening in 1991.

Edmonton Power submitted that it considers that relying on the current spot market price of gas is not appropriate for the benefit analysis because spot market purchases are generally interruptible. Therefore, for a utility that has the obligation to serve its customers continuously, the spot market should not be considered the sole means for relying on gas supply. However, Edmonton Power acknowledged that recent reviews of gas price forecast showed lower gas prices. Therefore, Edmonton Power recalculated operating benefits using the EUPC low growth gas price forecast. It concluded that operating benefits were in the order of $9 million if Genesee 1 is built in 1993 rather than 1994 and either the average load growth forecast or the low load growth forecast materializes.

With respect to environmental costs that may be associated with the operation of Genesee 1, Edmonton Power stated that Genesee 1 would meet all current environmental standards in Alberta and would also meet future standards as required. The cost of meeting current standards is included in plant costs used in the comparison of benefits and costs.

Edmonton Power offered to credit all the cost savings of displacing higher-priced generation to the capital cost of Genesee 1 to ensure that the unit would enter the rate base at the lowest possible cost. It submitted that if Genesee 1 is commissioned in 1993 and the need does not materialize, it will propose to the PUB that Genesee 1 receive full Allowance for Funds Used During Construction (AFUDC) treatment and the normal AFUDC rate, and then, credit all operating benefits, both internal and export, toward reduction in capital costs. While it was confident that early completion would result in some benefits to the AIS, Edmonton Power acknowledged that, if negative operating benefits are realized by operating Genesee 1, it expected Alberta customers to absorb the cost. Edmonton Power also stated that if Genesee 1 is built in 1993 and is not needed, it will not try to put it in the rate base until needed.

Edmonton Power testified that the AIS could realize additional operating benefits if some of the energy generated by Genesee 1 is exported out of the province. However, it stated that potential export markets are speculative at this time; therefore, Edmonton Power did not include export benefits in its economic analysis. It is also prepared to credit the benefits from exports against the capital cost of Genesee 1 providing the PUB does not penalize Edmonton Power with reduced AFUDC. Nevertheless, Edmonton Power indicated it had held talks with B.C. Hydro and there was interest in energy sales to B.C., since B.C. Hydro is an energy-constrained system. Also, Edmonton Power indicated that Alberta utilities are close to signing a deal with Bonnyville Power for the sale of energy, equivalent to approximately 100 MW.

Edmonton Power recommends completing Genesee 1 for 1993 because operating benefits would exceed incremental construction costs and operating expenses at all forecast levels of gas price. It stated that savings would accrue regardless of load demand growth. Edmonton Power did not recommend deferral beyond 1993 because it considers that continual deferral of Genesee 1 can only result in long-term price increases to consumers.

Edmonton Power submitted that if Genesee 1 is deferred to 1994 and the need materializes in 1993, the AIS would have to spend up to $12 million per year on firm capacity purchase from B.C. Hydro. At the end of 1 year, $12 million would be gone, the cost of completing Genesee 1 would have risen by $13 million, interest would have increased by $56 million, and Alberta would have lost the opportunity of 1 year of operating benefits. It also stated that long-term projects of this magnitude ought not to be stopped, once significant capital investment has been committed, based on cyclical variations in the business cycle or based on swings in volatile fuel costs.

5.3.2 Views of the Interveners

The interveners generally argued that the advantage of completing Genesee 1 was largely in offsetting fuel costs for operating higher-cost plants in the AIS. They submitted cost-benefit analyses under different assumptions on load growth as well as natural gas price. Table 3 shows the different natural gas prices used by each utility in 1993.

TransAlta submitted a 1-year calculation of operating benefits for a case in which Genesee 1 is commissioned in 1993 versus 1994. It indicated that, under the high case forecast, and for gas prices

ranging between $1 and $2 per GJ, it was possible to achieve benefits because of fuel-displacement savings and avoiding capacity purchase from B.C. Hydro. However, it indicated that, if the average or the low case forecast materializes, the fuel-displacement savings would not be large enough to offset the carrying cost of building the unit ahead of need plus its fuel, operating, and maintenance costs for that year.

TransAlta explained that its calculations were based on the assumption that $177 million ($90 million uncommitted plus $87 million committed) could be deferred and that $9 million of firm capacity purchase would be necessary if the high load growth forecast materialized. However, during cross-examination, TransAlta acknowledged that the $90 million uncommitted included $30 million of contingency and that removal of all or portions of the contingency amount would decrease carrying cost; therefore, benefits could increase. Also, TransAlta agreed that if Genesee 1 is installed in 1993 and the low load growth forecast materializes, fuel savings realized from 1994 to 1997 may offset losses in 1993. Furthermore, TransAlta acknowledged that its cost-benefit analysis did not include potential exports of electric energy, which could increase benefits.

TransAlta did not accept Edmonton Power's cost-benefit analysis. It used a gas price forecast in 1993 which was 37 cents below the base price used by Edmonton Power and indicated that, on top of using a higher gas price, Edmonton Power added transportation charges to the gas price which were unrealistic.

TransAlta stated that there is a "strong possibility" that gas prices in 1993 may be lower than the price used by Edmonton Power in its analysis. However, TransAlta also acknowledged the "possibility" that gas prices may be higher. It believed that significant gas price uncertainty existed; therefore, it submitted that uncertainty must be recognized. TransAlta concluded that the decision to commission Genesee 1 in 1993, or to defer it, hinged on future gas prices.

TransAlta also stated that capacity available from the new Medicine Hat unit to be commissioned in 1993 would be at no cost to Alberta. Even if there are payments for that capacity, the monies would remain in Alberta.

Alberta Power also submitted an economic analysis to justify the delay in construction of Genesee 1 after 1993. It submitted that building Genesee 1 for 1994, thereby deferring $175 million for 1 year, would save the AIS $12 million. Another $10 million would be saved by deferring operating and maintenance costs. Total savings would be $22 million. It indicated that this would be partially offset by the displacement of more expensive generation if Genesee 1 is built in 1993 versus 1994. Alberta Power expected that if the low load growth forecast materializes, there would be more benefits as a result of deferring Genesee 1 because at lower loads there would be less gas displacement savings.

Alberta Power was of the view that committed funds, which have yet to be spent, can be deferred or saved. Therefore, it did its calculations assuming that the full $177 million could be deferred. However, Alberta Power accepted that all the committed portion may not be totally deferrable and that there could be penalties for leaving existing contracts.

Alberta Power also recognized that the future gas prices are an important factor in determining the economic benefit of early completion of Genesee 1.

Alberta Power submitted that the EUPC gas price forecast is used for input into the economic models which drive the electric forecast. As such, it is an average Alberta price. However, Alberta Power

indicated that it considers these average prices inappropriate to calculate gas-displacement benefits because other prices apply to industrial consumers such as power plants. Furthermore, Alberta Power submitted that field gate gas prices are not appropriate; in fact, nominal values at the burner tip should be the proper price to use. Alberta Power considered that a gas price of $1.25 per GJ was much closer to the burner tip price in 1993 than the $2.18 per GJ used by Edmonton Power. It indicated that using $1.25 per GJ would translate into $7 million savings to the AIS if Genesee 1 is built in 1994 versus 1993, assuming a 75 per cent gas displacement and $177 million of capital cost deferred.

Respecting potential export markets, Alberta Power indicated that B.C. Hydro is seeking to purchase energy equivalent to 100 MW average per year, for 4 years starting in 1991.

Alberta Power submitted that to have the SPC tie providing capacity assistance to the AIS in 1993 would cost $4 million, and that any energy imported from Saskatchewan would be priced between 1.4 cents to 2.4 cents per kW•h.

IPCAA suggested that there is a great degree of uncertainty about the magnitude of perceived benefits because of the gas price forecast. Therefore, IPCAA submitted that the benefits alluded to by Edmonton Power are highly speculative.

The International Brotherhood of Electrical Workers (IBEW) testified that the construction of Genesee 1 will benefit IBEW locals and other Alberta trade unions, as well as all Albertans, by providing much needed jobs in these uncertain economic times.

The Trades Councils submitted that an immediate recommencement of construction of Genesee 1 was in the interest of Albertans who work in the construction industry and Albertans at large. They indicated that, if Genesee 1 is delayed after the 1993 collective bargaining round, cost increases in the order of $6 to $8 million will occur because of increases in actual wages. The Trades Councils also pointed out that there is a labour supply with collective agreements in place to build now and that if Genesee 1 is deferred, there may not be enough labour supply owing to other parallel industrial developments.

Fording Coal submitted that it was certain that any deferral would add to the project cost and that the advantages demonstrated by Edmonton Power showed that building Genesee 1 for 1993 was a win-win situation.

5.3.3 Views of the Board

The Board scrutinized the applicant's and interveners' calculations of costs and benefits and prepared a number of cost comparisons for various alternative courses of action available to complete the plant. The Board accepted the components of costs, as submitted by Edmonton Power, for each of the possible commissioning dates: 1993, 1994, 1995, and 1998. They are set out in Table 2.

The intangible costs associated with the environment are expected to be captured in the costs of mitigation equipment incorporated in the above estimates. These costs will ensure that all current standards will be met by Genesee 1. The Board notes that significant environmental costs due to land disturbance in the vicinity of the plant have already been incurred and were considered during the initial approval process. Such costs are not relevant to the decision on timing of completion of the plant, under consideration here. In the event that environmental standards are changed and become applicable to Genesee 1, associated costs would have to be absorbed at the time.

Intangible costs associated with deferral of construction are difficult to quantify but, as discussed in Section 5.2.2 above, the Board is willing to accord them some weight in the decision.

As indicated earlier, Table 2 shows the as-spent costs to the end of 1990 and the additional capital costs to complete the project, depending on the year of completion. To determine, on a present-worth basis, if there is any significant difference attributable to building in 1993 instead of 1994, an analysis was done assuming two different expenditure patterns for the remaining capital costs associated with each commissioning date.

The first part of the analysis assumed all remaining capital costs were spent in the year of commissioning. With such an extreme deferral of costs, there is a slightly greater cost to meet a 1993 date, favouring a 1994 commissioning.

The second part assumed a more likely pattern of the remaining capital expenditures starting in 1991 and distributed through to a 1993 or 1994 commissioning date. This would slightly increase the cost of meeting a 1994 commissioning date as compared to a 1993 date. This slightly greater cost and the possibility of additional intangible costs, i.e. warranties, risk of obsolescence, etc. associated with deferral of the unit, increases the possibility that a 1993 commissioning date would yield savings in the costs of construction. However, any further increase in costs to meet a 1993 date, such as an accelerated construction schedule, could easily nullify the direct benefits associated with a 1993 date.

The Board concluded that a direct comparison of costs to complete the plant does not strongly favour either 1993 or 1994. However, that means that if the positive benefits of completing the plant earlier, as posited by Edmonton Power, are substantiated, they will be an even greater factor in the decision, since they will not be offset by greater costs in 1993.

The Board reviewed the potential operating benefits that could be obtained if Genesee 1 were installed before the need materializes. It accepts that operation of Genesee 1 as a base-loaded unit would displace generation at other power plants which are more expensive to operate. Therefore, there would be some fuel-displacement savings. However, these savings have to be balanced against the costs of fuelling Genesee 1 as well as its operating and maintenance costs.

The Board notes that the bulk of fuel-displacement saving comes from reduced gas-fired generation mainly at the Clover Bar generating station, and that a smaller portion comes from displacing more expensive coal-fired generation mainly at the Battle River and Sheerness plants. Therefore, the Board recognizes that the price of natural gas plays a decisive role in the realization of operating benefits.

To ensure complete understanding of the potential operating benefits, the Board conducted an analysis which indicated that running Genesee 1 does produce positive savings to the AIS for the range of load growth scenarios mentioned in Section 3.1.3. A drop in gas prices to slightly under $1 per GJ in 1993 would be required to turn the operating benefits to costs. These potential operating benefits are strictly the savings possible from displacing other units on the AIS net of fuel, operating, and maintenance costs of Genesee 1.

Thus, the Board accepts that there is a possibility that operating Genesee 1 ahead of strict need could yield positive operational benefits to the AIS. It notes, however, that the benefits are sensitive to the cost of gas; lower gas prices result in lower benefits. The benefits are also sensitive to the electric load, i.e. lower load would result in lower fuel-displacement savings. Current markets for natural gas are depressed and expectations are that they will continue to be weak for the next few years.

However, although future market conditions are difficult to forecast, conditions that lead to continuing gas prices less than $1 per GJ in 1993 seem unlikely. Therefore, the Board believes that the possibility of there being no benefits due to operating Genesee 1 in advance of need is small.

The Board recognizes that Edmonton Power has its own views of the likely cost of gas and the potential benefits that may accrue from early completion of Genesee 1 before 1994. While the Board is not convinced that completion before the 1994/95 winter peak will be necessary, it would not object to an earlier completion as long as the financial risk for early completion is accepted by Edmonton Power.

6 FINDINGS AND CONCLUSIONS

The Board's review of the positions and evidence presented at the hearing concludes that there are varying levels of uncertainty associated with each of the issues discussed. The ultimate decision represents a balancing of factors the Board believes relate to the public interest of Albertans.

The establishment of a window of need, namely, a period of time during which new capacity might be required to serve the AIS, involves assessing projected growth in energy and peak demand net of interruptible requirements.

Edmonton Power argued the window of need extended from 1993 (if the EUPC high load growth materializes) to 1998 (if the low forecast were realized). It also argued that current levels of interruptible load predicted by the utilities' short-term add-up forecast are not appropriate for future planning.

The interveners placed a lower probability on the EUPC high growth case and argued that significant levels of interruptible load plus recent trends in load growth suggest the window of need probably does not start in 1993. No one argued that the window would not start by 1994; however, some suggested the hearing be reconvened in 1992 to consider whether or not new capacity will be required in 1994.

The Board scrutinized the EUPC forecast and the assumptions on which it is based, including the level of interruptible load, applied some judgment to critical assumptions, and concluded that 1993 could not be precluded as a possible time of need for some capacity but the associated probability was low enough that the issue of need could not, on its own, justify approval of the application. The Board's review suggested a much stronger conclusion that new baseload capacity would be needed by 1994.

Other sources of supply could be used to meet needs whenever they occur and the Board reviewed the submissions carefully with a view to isolating those on which it would be prudent to rely. Suggestions were presented as short-term alternatives to proceeding with Genesee 1. No party presented them as appropriate long-term alternatives to meeting the needs of the AIS. Moreover, all parties recognized Genesee 1 as an approved facility that would be brought on stream at some time in future. The question was accepted to be, when should it be brought on stream? In any case, as discussed above, the alternatives presented were not supported by details or in a way that would allow comparison with Genesee 1, except as to general representations that they would be less costly in the short term (though not necessarily in the long term).

Once the Board had decided to recognize the new generating capacity at Medicine Hat and 40 MW of capacity installed under the small power program, it turned next to consideration of the other alternatives discussed at the hearing, and found none to be acceptable as an alternative to Genesee 1. It was recognized, however, that for limited load and short duration some of these options could assist in maintaining reliability on the system. This left the possibility that some capacity would be needed in 1993, and also suggested a significant probability that a new plant would be needed by 1994.

The extensive discussion at the hearing regarding the status of construction confirmed that the project is over 70 per cent complete and that what remains to be done is largely to put together components that are already available in storage. The Board accepts that the project is substantially complete and is, therefore, prepared to consider this status as a factor in its decision. The factor argues for timely completion of the unit as a means of avoiding unnecessary costs such as loss of warranty, risk of obsolescence, storage costs, and certain administrative and financial costs.

The Board considers the question of total costs associated with alternative commissioning dates within the "window of need" to be particularly significant. Significant incremental costs associated with a particular commissioning date would argue against that option. Our analysis showed only a slight advantage on this basis to completion in 1993, as compared to 1994. This advantage could be lost if further costs were required to accelerate construction to achieve 1993 completion. Our analysis also shows that completion in 1993 or 1994 is clearly better than completion in 1995 or later.

However, consideration of intangible costs associated with deferral strengthens the presumption that commissioning in 1993 could yield lower overall costs than commissioning in 1994. In any case, the fact that costs associated with either 1993 or 1994 completion are not significantly different, lends greater weight to any operating benefits that might be associated with earlier completion.

A significant component of the argument presented by Edmonton Power in support of early completion of the plant related to potential operating benefits that would offset costs of bringing construction forward from 1994 to 1993. These operating benefits result from displacement of plants using higher-cost fuels, in particular, natural gas. The interveners demonstrated that the size of any operating benefits depends on the price of natural gas in 1993 and argued this is another element of significant uncertainty.

The Board's analysis of this question confirmed some potential for operating benefits but suggested they disappear at a price of natural gas slightly below $1 per GJ in 1993. No direct evidence was submitted on actual burner tip fuel costs, so the Board is left with some uncertainty. However, the Board believes that current market conditions in Alberta have led to prices below their long-run equilibrium and as markets come into balance, higher prices will emerge. Burner tip prices below $1 per GJ in 1993 do not seem likely, so the Board accepts a reasonable likelihood that some operating benefits could be realized from displacement. While this does not argue conclusively for a 1993 completion date, the Board acknowledges that Edmonton Power's more detailed knowledge of the relevant costs might provide it some comfort in choosing the earlier completion.

In summary, the Board has reviewed the following elements of the application.

The Forecast of Energy Requirements

Recognizing the uncertainty inherent in projecting future demand for energy, the Board would not preclude 1993 as a date on which new capacity may be needed. However, it considers the possibility to be remote and because of the associated probabilities the Board would not accept need alone as a basis for approving a 1993 commissioning date.

Alternatives to Meet the Need

Existing capacity, including Medicine Hat and some small power projects, is insufficient to meet needs under the high forecast in 1993 or, assuming average load growth, in 1994. However, it is reasonable to expect that any shortage in LCC in 1993 that was small and of short duration would be manageable by the utilities. Nonetheless, the other options discussed at the hearing cannot be viewed as substitutes for Genesee 1.

Costs and Benefits

The direct costs associated with various commissioning dates do not strongly favour earlier completion. But neither do they argue strongly that the project should be deferred and, when consideration of intangible costs is included, an earlier completion date is favoured. Environmental considerations do not affect the decision on timing.

The benefits of displacing higher-cost generation are dependent on future, and therefore uncertain, gas prices. The probabilities favour early completion; the risks of an adverse outcome because of early completion are small.

Potential benefits to the economy, while not a large factor in the decision, favour earlier commissioning.

Other Considerations

The notion of flexible planning has merit but is more relevant to a choice involving definitive alternatives than to a decision on timing of an already approved alternative. The suggestion that a new hearing be held in 1992 to consider these questions again was considered but not adopted because of the combination of arguments that favour early completion: not only possible need but also possible benefits. Moreover, the approach would involve its own uncertainties and costs.

Conclusion

There is uncertainty associated with each of the elements discussed above. Projections of need suggest a completion date of 1994 but do not preclude the possibility the plant could be needed in 1993. Other supply options could be helpful in the event of temporary shortages but cannot be considered a prudent alternative to Genesee 1. Potential economic benefits provide some support for an earlier completion date but are not conclusive because they depend on the uncertain future load and uncertain future gas prices. Having weighed the various aspects of the application, the Board has concluded that continuing deferral of completion of Genesee 1 could result in the foregoing of some economic benefits, the imposition of unnecessary future costs, and some increase in risk to the AIS, and is, therefore, not in the public interest.

7 DECISION

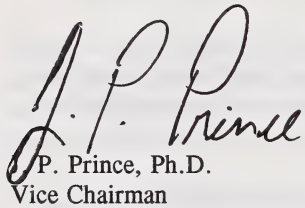
The Board has considered Edmonton Power's application and the evidence presented at a hearing held on 15 August 1991. Having regard for its responsibilities under the Hydro and Electric Energy Act, the Board is prepared, with the authorization of the Lieutenant Governor in Council, to issue an approval to Edmonton Power requiring the second unit at the Genesee power plant, Genesee 1, to be completed by October 1994.

The Board would not restrict Edmonton Power from completing the unit earlier to take advantage of the benefits described by Edmonton Power at the hearing. Completion of the unit for service prior to the 1994/95 peak demand would be a decision for which Edmonton Power will have to accept full responsibility. The Board assumes such a decision would be made only if the associated benefits discussed at the hearing were highly likely to be realized.

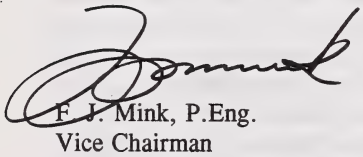
The order would be of the form set out in Appendix A of this report, and would be subject to the terms and conditions contained therein.

DATED at Calgary, Alberta, on 6 April 1992.

ENERGY RESOURCES CONSERVATION BOARD



J. P. Prince, Ph.D.
Vice Chairman



F. J. Mink, P.Eng.
Vice Chairman

R. G. Evans, P.Eng.
Board Member

TABLE 1 THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The City of Edmonton (Edmonton Power) D. Tadman	A. Pettican, P.Eng. F. Shinyei, P.Eng. D. Topping, P.Eng.
TransAlta Utilities Corporation (TransAlta) T. Dalgleish	J. Tapics, P.Eng. D. Way, P.Eng.
Alberta Power Limited (Alberta Power) M. Romanow	R. Frey, P.Eng. R. Baer, P.Eng. J. Walker, P.Eng.
The City of Calgary D. Short	
Industrial Power Consumers Association of Alberta (IPCAA) A. McLarty	
Fording Coal Limited P. McIntyre	
Northern Alberta Building Trades Council and Provincial Building Trades Council	M. Hall
County of Leduc B. Sjolie	
Western Oldman Water Users Association and W. Arsene W. Arsene	
Energy Consulting Inc. and The Town of Stettler	A. Jackson
Alberta Cogeneration Council	K. Logan T. Whitford
The International Brotherhood of Electrical Workers (IBEW)	D. Turner

TABLE 1 THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Northwest Territories Building and Construction Trades Council	R. Blakely
Energy Resources Conservation Board staff M. Asgar-Deen, P.Eng. J. Wilson, P.Eng. P. Wickel, P.Eng.	

TABLE 2 FORECAST FINAL COST TO COMPLETE GENESEE 1 FOR VARIOUS COMMISSIONING DATES (millions of as-spent dollars)

	1993 COMPLETION DATE	1994 COMPLETION DATE	1995 COMPLETION DATE	1998 COMPLETION DATE
	Capital	Capital	Capital	Capital
Spent to December 1990	199	199	199	199
Additional Costs	177	190	201	258
Forecast Final Cost	376	389	400	457

TABLE 3 1993 GAS PRICE FORECAST (dollars per GJ)

Edmonton Power	2.18
TransAlta	1 to 2
Alberta Power	1.25

APPENDIX A
FORM OF APPROVAL*

THE PROVINCE OF ALBERTA

HYDRO AND ELECTRIC ENERGY ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a power plant of
The City of Edmonton in the Genesee area

APPROVAL NO. HE

WHEREAS The City of Edmonton is the holder of Approval No. HE 8505 authorizing the construction and operation of the Genesee power plant; and

WHEREAS The City of Edmonton, by Application No. 910336 registered on 1 March 1991, applied to the Energy Resources Conservation Board for approval of a November 1993 commissioning date for the second generating unit, Unit No. 1, at the Genesee power plant; and

WHEREAS the Board is prepared to issue an approval for Unit No. 1 to be commissioned by October 1994, subject to the conditions herein contained, and the Minister of the Environment has given his approval, hereto attached, insofar as matters of the environment are concerned; and

WHEREAS the Board deems it desirable to revise and consolidate Approval No. HE 8505.

THEREFORE, the Energy Resources Conservation Board, pursuant to the Hydro and Electric Energy Act, being chapter H-13 of the Revised Statutes of Alberta, 1980, and the Lieutenant Governor in Council having given his authorization by Order in Council, numbered O.C._____/92 and dated _____ 1992, hereby orders as follows:

1. The construction and operation by The City of Edmonton (hereinafter called "the Operator") of the Genesee power plant and associated facilities located in the Genesee area, is approved, subject to the terms and conditions herein contained.

2. Subject to the other provisions of this approval, the power plant shall be constructed and operated in accordance with

---

* This is only a form of approval. The approval, when issued, may have minor variations from that set out here.

(a) Application No. 780024 by the Operator to the Board dated 12 January 1978 and supplementary information and evidence given in support of the application at a hearing on 25 July 1978,

(b) Application No. 810683 by the Operator to the Board dated 20 September 1981 and supplementary information and evidence given in support of the application at a hearing on 25 November 1981,

(c) Application No. 821000 by the Operator to the Board dated 18 October 1982,

(d) Application No. 830799 by Alberta Power Limited to the Board dated 22 August 1983 and supplementary information and evidence given in support of the application at a hearing on 28 September 1983,

(e) Board Proceeding No. 840837 and information and evidence given at a hearing on 22 January 1985, and

(f) Application No. 910336 by the Operator to the Board dated 1 March 1991 and supplementary information and evidence given in support of the application at a hearing on 15 August 1991.

3. (1) The power plant shall consist of two units, each of 400-megawatt nominal capacity.

(2) The second unit, Unit No. 1, shall be commissioned such that it is available to the system by October 1994, unless the Board otherwise stipulates.

4. The power plant and related facilities shall be located generally as shown on the attachment to this approval, marked Appendix A.

5. The power plant shall be cooled by a cooling pond constructed in accordance with the following provisions:

(1) The cooling pond shall be located generally as shown in Appendix A.

(2) The cooling pond shall be designed for and operated at a maximum full supply level of 731.5 metres above sea level.

(3) The Operator shall maintain a buffer zone around the cooling pond.

(4) The buffer zone required by subclause (3) shall extend not less than 10 metres measured horizontally from the cooling pond shoreline at the full supply level.

(5) The cooling pond shall be provided with independent make-up and blowdown pipeline facilities from the North Saskatchewan River to the plant site. The pipelines shall be located generally as shown on Appendix A on a right of way not to exceed 30 metres in width.

6. (1) Ash from the power plant shall be disposed of in worked-out sections of the coal mine.

(2) Until such time as the mine can accept ash from the power plant, a temporary ash disposal area may be used.

(3) The temporary ash disposal area required for disposal of ash shall be located generally as shown in Appendix A, or as otherwise stipulated by the Board.

(4) The Operator shall, in consultation with the Department of the Environment, investigate means of salvaging topsoil for use in reclamation of the temporary ash disposal area.

7. Notwithstanding the foregoing provisions, the permitted area of the power plant and related facilities shall include Sections 22 to 27 inclusive and the South halves of Sections 34 and 35, all in Township 50, Range 3, West of the 5th Meridian, or as otherwise stipulated by the Board.

8. (1) Not later than 30 September 1992, the Operator shall provide to the Board a complete revised project schedule for the plant covering planning, design, construction and commissioning phases, and showing all key dates in the schedule.

(2) The Operator shall submit to the Board quarterly progress reports indicating any major deviation from the schedule which may cause a delay in the in-service dates of the generating units.

(3) The Operator shall notify the Board in writing within 1 month upon the commissioning of each unit.

9. (1) Insofar as it pertains to matters of the environment, this application is subject to the approval of the Minister of the Environment.

(2) The approval of the Minister of the Environment, in accordance with subclause (1), is attached hereto as Appendix B, and this approval is subject to the terms and conditions therein contained.

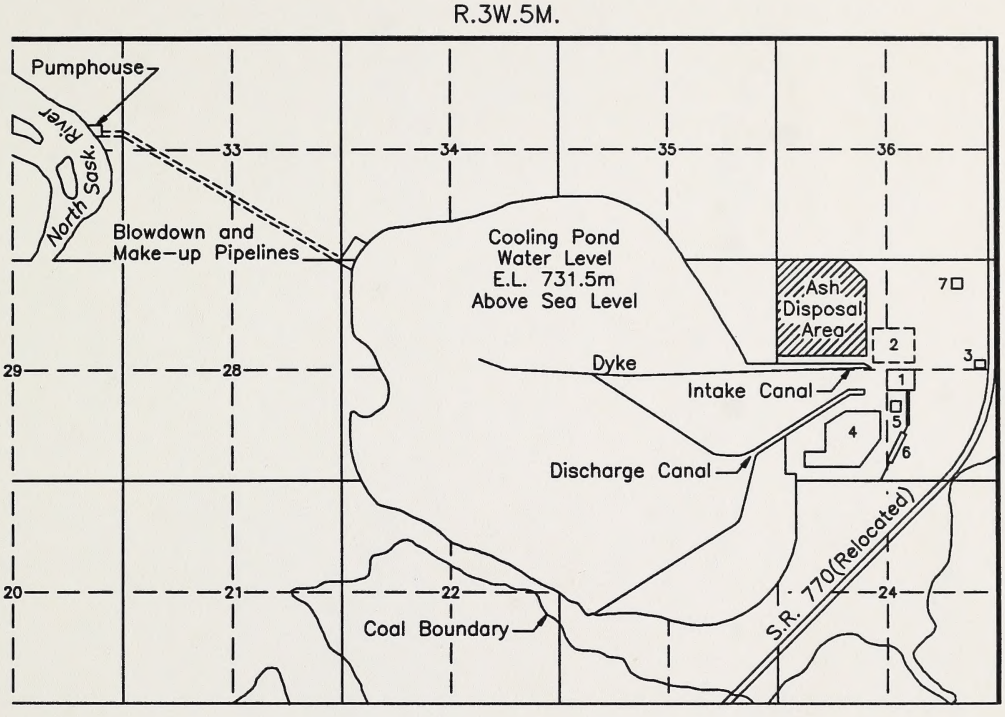
10. (1) Attached hereto as Appendix C, and made part of this approval, is the Order of the Lieutenant Governor in Council authorizing the granting of this approval.

(2) This approval is subject to the terms and conditions, if any, prescribed by the Order of the Lieutenant Governor in Council, as set out in Appendix C.

11. Approval No. HE 8505 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this _____ day of _____, 1992.

ENERGY RESOURCES CONSERVATION BOARD



LEGEND

1. Power Plant
2. Switchyard (Proposed)
3. Station Parking
4. Waste Pond
5. Ash Handling
6. Coal Handling Plant
7. Water Reservoir

GENESEE POWER PLANT AND FACILITIES

APPENDIX A TO APPROVAL NO. HE

PREVIOUS APPROVAL NO. HE 8505

N.L.C. - B.N.C.
3 3286 11429288 7